Status Report

SIMULATION STUDIES OF OIL RECOVERY FROM FIELD PERMEABILITY MODIFICATION TREATMENTS

Project BE4C, FY93 Annual Research Plan, Milestone 3

by

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ABSTRACT

The objective of Task 3 of Project BE4C is to compare results from NIPER's permeability modification simulator with field performance data. A 40-acre, five-spot-pattern pilot area was selected for simulation studies. Field data and information on permeability modification treatments were provided by an independent oil producer and a major chemical company. Field data included location and depth of each well, oil relative permeability, capillary pressure, well logging of an injection well, core analysis results on four wells, average porosity, average permeability, initial water saturation, oil viscosity, reservoir temperature, production and injection history, and injection profiles before and after polymer gel treatments.

A five-layer reservoir model having dimensions of 5,000 ft x 3,875 ft x 96 ft with 4 injection wells and 11 production wells was used to represent the field. For simulation purposes, 15 producing wells outside the pilot area were represented by 6 producing wells. The permeability distribution in each layer was determined by weighting the known permeabilities in four injection wells and two other wells using an inverse distance as the weighting parameter. The permeability distributions in the four injection wells were determined using a flowmeter survey and Hall plot data.

Results from the preliminary history match indicate that, based on the data available, the overall reservoir characteristics have been successfully simulated for the first 8 years of oil recovery. However, a better match between the simulated results and field data may be obtained by modifying the parameters used to characterize the reservoir, such as the ratio between the oil relative permeability and the water relative permeability or the bottomhole pressures.

INTRODUCTION

Polymer gel treatments have been used in many fields to reduce layer permeability contrast and improve sweep efficiency and increase oil recovery with mixed results.[1-2] To apply this technology successfully, understanding the reservoir characteristics and gel transport phenomena in the reservoir is important. In 1990, a simulator that includes these features was developed.[3-4] The simulator has been used to investigate the effects of reservoir characteristics, gel-treatment

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initiation time, and gel properties on oil recovery from a gel treatment in waterfloods and polymer floods.[4-8] To verify the simulator with field gel treatment performance, simulation studies of field gel treatments were conducted.

This status report describes the progress made toward the simulation of a Louisiana pilot field that had been treated with Xanthan/Cr(III) gels to reduce water channeling and increase oil recovery. The average porosity of the reservoir is 32%, the average permeability is 142 mD, original oil viscosity is 3.06 cP, and reservoir temperature is 100° F. Table 1 summarizes some of the reservoir and fluid data. This field was discovered in 1919 and unitized in 1970. Production history showed that the cumulative oil recovery from the waterflood was relatively low compared to that from the primary production. Poor oil recovery from the waterflood was attributed to severe channeling of injected water through the multi-layered zones of high permeability. To improve volumetric sweep efficiency, injection profiles were modified using a gelled polymer. Three phases of polymer gel treatments were implemented between 1983 and 1985. The first and second phases of gel treatments were conducted in a 40-acre, five-spot-pattern pilot area. In May of 1983, four injection wells were treated with a biopolymer gel. However, because of lack of an injectivity response and the modest production response at five internal producers, the same four injection wells were retreated with an improved gel system in late 1984. Production data from all the producing wells surrounding the pilot area gave encouraging results from both phases of gel treatments. Hall[9] plots (pressure versus injection rate) showed that an apparent decrease in injectivity was observed in each of the four injection wells after the injection of the 2nd polymer gel system, thereby indicating that injection water was diverted to a previously unswept zone. Data from pre- and post-polymer surveys indicated that a significant change in the injection profile occurred in all four injection wells. Favorable results from the pilot effort led to the expansion of the gel treatments to fieldwide.

To compare results from NIPER's permeability modification simulator with field gel treatment performance, information on gel treatments and field data of a pilot area were collected, analyzed and used to construct a reservoir model. History matching has been conducted for the period prior to the start of the polymer gel treatments.

ACKNOWLEDGMENTS

DESCRIPTION OF THE RESERVOIR MODEL

The pilot area that is being simulated consists of four injection wells and five producing wells inside and 15 producing wells outside the pilot area. This area was selected based on the performance of gel treatments in the four injection wells. Hall plot analyses (pressure versus injection rate) showed that an apparent decrease in injectivity was observed in each of the four injection wells. Data from pre- and post-polymer surveys indicated that a significant change in the injection profile occurred in all four injection wells. Based on the locations of these 24 wells and the net pay of the reservoir, a reservoir model having dimensions of 5,000 ft x 3,875 ft x 96 ft was constructed, as shown in Fig. 1. The total net pay was divided into five layers according to the well logging data of injection well I-13. Each layer was divided into 15 x 16 grid blocks. For simulation studies, the 15 producing wells outside the pilot area were divided into six groups. Each group was represented by a single well. Figure 2 shows the size of each grid block and locations of the four injection wells and five producing wells inside and six producing wells outside the pilot area.

DETERMINATION OF PERMEABILITY DISTRIBUTIONS

To simulate reservoir performance, permeability distribution of the entire reservoir is required. Core analysis results on permeability distribution are only available for two wells. These two wells are inside the two grid blocks, (1, 8) and (15, 12) (Fig. 2). In Fig. 2, blocks (1, 1) and (16, 15) are located at the lower left-hand and upper right-hand corners, respectively. Calculated average permeabilities in each of the five layers are shown in Table 2. The other information available for calculating the permeability included the flowmeter survey and Hall plot data of each of the four injection wells. The total product (kh) of permeability (k) and layer thickness (h) for injection wells 5, 7, 13, and 14 were 1,000, 2,800, 5,800, and 1,250 mD-ft, respectively. Based on the above information and the thickness of each layer, the permeability distributions in the four injection wells were calculated (Table 2). The permeability data obtained were then used to determine the permeability distribution in each of the five layers of the reservoir model by weighting these data using an inverse distance as the weighting parameter. Figures 3a to 3e show the permeability distributions. The calculated average permeability from the five permeability distributions shown in Figs. 3a to 3e was 16.9 mD, compared to 142 mD provided by the independent oil producer. The discrepancy between these two values could have been created if the oil producer did not consider the permeability distributions of the four injection wells.

DEVELOPMENT OF FLUID DATA

To begin history matching it was necessary to obtain the proper data on the fluid properties within the reservoir. The information was calculated from relative permeability and capillary pressure graphs provided by the independent oil producer. Although the graphs contained data on the permeability relative to oil (k_{ro}), they did not contain data on the permeability relative to water (k_{rw}). The permeability relative to water was calculated using a graph of k_{ro}/k_{rw} vs. water saturation (S_w) for an irreducible water saturation of 0.35.[10] Table 3 shows the relative permeability data and capillary pressure data used in the simulation runs.

POLYMER RHEOLOGY

The effect of polymer concentration, C_p in ppm, on solution viscosity, μ_p in centipoise, was modeled by a third- order polynomial:

$$\mu_p = \mu_b + a_0 + a_1 C_p + a_2 C_p^2 + a_3 C_p^3 \qquad (1)$$

where $a_0 = 0.521444$, $a_1 = -0.04729$, $a_2 = 0.0001056$, $a_3 = -5.2166$, and μ_b (in centipoise) is brine viscosity. The shear rate dependence of polymer viscosity was modeled by Meter's equation.[3] The shear rate, $\gamma_{1/2}$, at which the viscosity is half of zero-shear-rate viscosity was modeled as:

$$\gamma_{1/2} = (1.4 \times 10^9)C_p^{-2.6022} \qquad (2)$$

HISTORY MATCH

There are two alternatives for simulating oil production with NIPER's Permeability Modification Simulator: Oil production may be based on either a rate constraint or a pressure constraint. In general, a rate constraint will provide a more accurate match of the production history, but a pressure constraint is preferred as it is considered to be more useful in predicting future recovery. In addition, the simulator's execution may cease if the simulator cannot precisely match the specified production and injection rates under the field conditions that were given. The independent oil producer provided oil production data and water injection data covering 5 years of primary production, 8 years of waterflooding, 7 days of gelled polymer injection for the first phase and 8.3 days of gelled polymer injection for the second phase of gel treatment, and another 7 years of waterflooding. Primary production started in 1970. To simulate field performance, a pressure-constraint mode was used during primary production. During waterflood simulation runs, a pressure-constraint mode was used for all production wells, and a rate-constraint mode was used for all injection wells.

Since bottomhole pressure is available only at the beginning (512 psi) and end (15 psig) of primary production, a simulation run was begun using a rate constraint for all production wells during primary production and waterflood to obtain the first approximation of bottomhole pressures at intermediate years. The simulator, when given a rate constraint for oil production, will automatically calculate the appropriate bottomhole pressures for each of the wells. In addition, the simulator provides bottomhole pressures for each of the five layers in the reservoir. Using the calculated bottomhole pressure in the fifth layer as a basis, the bottomhole pressures for the other four layers were then determined using a pressure gradient of 0.4 psi/ft. The simulation run was then repeated using the calculated bottomhole pressures and a pressure-constraint mode for the production wells during primary production and waterflood to obtain new oil production rates while the injection wells were allowed to remain under a rate constraint during waterflood.

RESULTS AND DISCUSSION

Figures 4 through 8 show the results of a preliminary history match which covers the initial 5 years of primary production and the first 3 years of waterflooding. The preliminary history match indicates that, in general, the overall reservoir characteristics have been successfully simulated for the first 8 years of oil recovery. However, to ensure that the reservoir model will be acceptable for recovery prediction, it is necessary to obtain an accurate model of the reservoir characteristics. Note that a precise match of the past oil recovery is not required; the model is to provide only an approximation of the actual recovery. To complete the history match, many options are available. One solution is to modify the simulated bottomhole pressures until the oil recovery levels shown by the simulator are more accurate. However, this may not be the best solution. Other parameters could also have an effect on the history match. Several wells outside of the pilot area have been grouped together due to the demands of the simulation itself, such as the memory constraints of the PC. If the combination of several wells has an adverse effect on the results, then the simulation may benefit from the addition of another well. In addition, other properties, such as permeability distribution and fluid characteristics, may be modified to more accurately describe the reservoir conditions. The use of a different relative permeability ratio between oil and water may also be necessary to correct for the production deficiencies before the history match for the rest of the flood is continued. Further study is needed to perform an accurate history match, as it is necessary to determine which alternative (or combination of alternatives) will provide the most accurate solution. The initial results were encouraging, as the oil production calculated by the simulator appears to be within reason. The inaccuracies of the oil production history generally fall within the normal parameters associated with any reservoir simulation; however, certain aspects of the history match should be addressed. In some years the

production from wells P-9, P-10, and P-11, corresponding to eight production wells outside the pilot area, is insufficient. Given the range of known bottomhole pressures permitted with this particular field, it will be necessary to change a reservoir parameter other than bottomhole pressure to correct for the deficiency. Considering the volume of oil production from the eight wells, the simulation may benefit from the addition of another producing well in that region.

SUMMARY AND CONCLUSIONS

1. Based on the available data, a five-layer reservoir model that contains 4 injection wells and 11 production wells was constructed.

2. A preliminary history match was performed which covers 5 years of primary production and 3 years of waterflooding.

3. In general, the results of the preliminary history match appeared to be within acceptable limits, although further study is needed.

4. The addition of another producing well outside of the pilot area may be necessary to correct for certain production deficiencies that are not within acceptable limits.

5. The use of a different relative permeability ratio between oil and water may also be necessary to correct for the production deficiencies before the history match for the rest of the flood is continued.

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Initiation Time and the Effect of the Degree of Gel Penetration on Oil Recovery in Permeability Modification Treatments Using Gelled Polymers. DOE Report NIPER-489, 1990. Available from DOE Bartlesville Project Office, Bartlesville, OK.

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Table 1. - Summary of reservoir data

Geology

Dip of formation, ft/mile	430
Depth, ft	1,000-1,400
Net pay, ft	96

Rock Data

Average porosity, %	32
Initial water saturation, %	41
Horizontal permeability, mD	142
Vertical permeability, mD	124

Fluid Data

Oil gravity, ^{O}API	37.1
Original solution gas GOR, SCF/STB	96
Saturation pressure, psia	512
Original formation volume factor, RB/STB	1.079
Original oil viscosity, cP	3.06
Initial reservoir pressure, psia	512
Reservoir temperature, ^{O}F	10
Injected water viscosity, cP	0.74

Table 2. - Permeabilities used to obtain the permeability distributions of the reservoir model

Layer	Permeability, mD					
	Well I-5	Well I-7	Well I-13	Well I-14	Grid block (1, 8)	Grid block (15, 12)
1	13	35	73	16	-	-
2	17	73	81	48	336	263
3	4	19	12	6	16	23
4	33	63	219	28	281	314
5	4	15	15	4	31	18

Table 3. - Relative permeability and capillary presure data

Saturation	Relative permeabilities			Capillary pressure, psi	
	Oil	Water	Gas	Oil to water	Gas to oil
0.10	0.0	0.0	0.010	0.0	0.0
0.12	0.0	0.0	0.016	0.0	0.0
0.14	0.005	0.0	0.020	0.0	0.0
0.16	0.006	0.0	0.035	0.0	0.0
0.20	0.015	0.0	0.056	0.0	1.30
0.22	0.020	0.0	0.072	0.0	1.45
0.24	0.025	0.0	0.090	0.0	1.60
0.26	0.035	0.0	0.11	0.0	1.70
0.28	0.040	0.0	0.13	0.0	1.90
0.30	0.055	0.0	0.16	0.0	2.03
0.32	0.070	0.0	0.18	40.0	2.30
0.34	0.086	0.0	0.21	35.0	2.60
0.36	0.105	0.0	0.24	13.5	2.90
0.38	0.136	0.0	0.28	11.0	3.20
0.40	0.160	0.00026	0.32	9.25	3.70
0.42	0.20	0.00034	0.36	8.00	4.20
0.44	0.24	0.00075	0.40	6.80	4.95
0.46	0.28	0.00104	0.44	6.00	5.45
0.48	0.34	0.00176	0.49	5.25	6.20
0.50	0.40	0.00200	0.54	4.75	7.20
0.52	0.44	0.00227	0.59	4.20	8.20
0.54	0.52	0.00560	0.64	3.75	9.45
0.56	0.60	0.00600	0.68	3.25	11.20
0.58	0.68	0.01111	0.73	3.00	13.20
0.60	0.78	0.01067	0.78	2.65	15.70
0.62	0.78	0.01046	0.82	2.45	19.20
0.64	0.78	0.01750	0.85	2.25	23.70
0.66	0.78	0.02150	0.88	2.00	35.20
0.68	0.78	0.03500	0.90	1.90	38.70
0.70	0.78	0.03143	0.91	1.75	38.70
0.72	0.78	0.04444	0.92	1.65	38.70
0.74	0.78	0.05000	0.935	1.52	38.70
0.76	0.78	0.05000	0.945	1.48	38.70
0.78	0.78	0.05000	0.956	1.45	38.70
0.80	0.78	0.08571	0.965	1.33	38.70
0.82	0.78	0.05625	0.976	1.30	38.70

5,000 FT

3,875 FT

OOIP = 58.75 x 10^6 BBL

POROSITY = 32%

OIL VISCOSITY = 3.06 cP

INITIAL OIL SATU. = 59%

RESERVOIR TEMP. = 100° F

Thickness = 16 FT

Thickness = 11 FT

Thickness = 12 FT

Thickness = 19 FT

Thickness = 38 FT

I	Low-Permeability Layer
II	High-Permeability Layer
III	Low-Permeability Layer
IV	High-Permeability Layer
V	Low-Permeability Layer

Fig. 1 - 5-layer reservoir model.

i=1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	i=16
i=1 j=15	(2, 15)	(3, 15)		P-9									(14,15)	(15, 15)	i=16 j=15
(1, 14)															(16, 14)
P-11 (1, 13)	P-10 (2, 13)													P-7	(16, 13)
(1, 12)															(16, 12)
(1, 11)							P-8								(16, 11)
(1, 10)				I-5								I-7			(16, 10)
(1, 9)								P-3							(16, 9)
(1, 8)															(16, 8)
(1, 7)						P-4		P-5							(16, 7)
(1, 6)											P-6				(16, 6)
(1, 5)	P-1 (2, 5)														(16, 5)
(1, 4)								P-2							(16, 4)
(1, 3)				I-13								I-14			(16, 3)
(1, 2)															(16, 2)
i=1 j=1	(2, 1)	(3, 1)	(4, 1)										(14, 1)	(15, 1)	i=16 j=1

Y DIRECTION →

X DIRECTION →

1.5a

2a   a   1.5a

a = 250 ft
I = Injection well
P = Producing well

Fig. 2 - Grid-block size and well locations.

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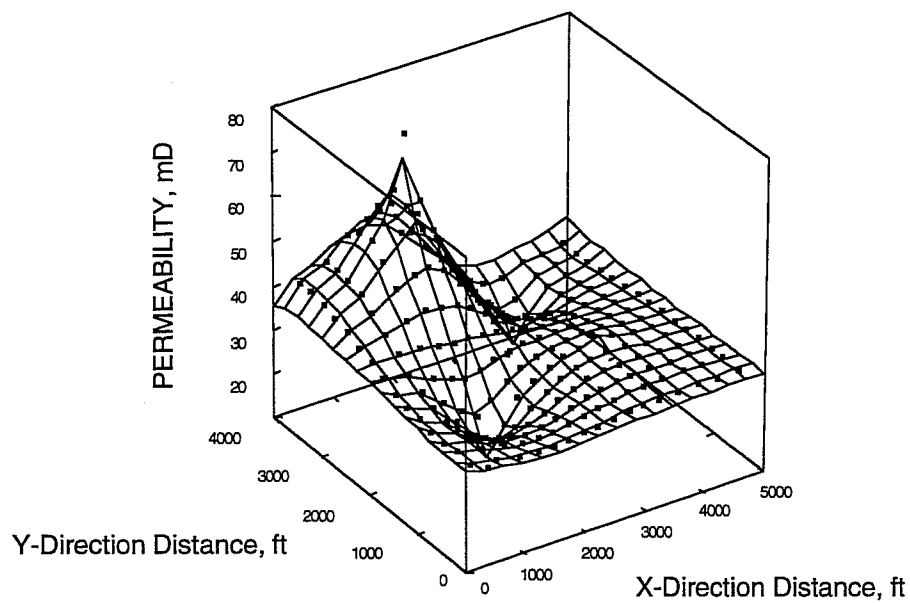
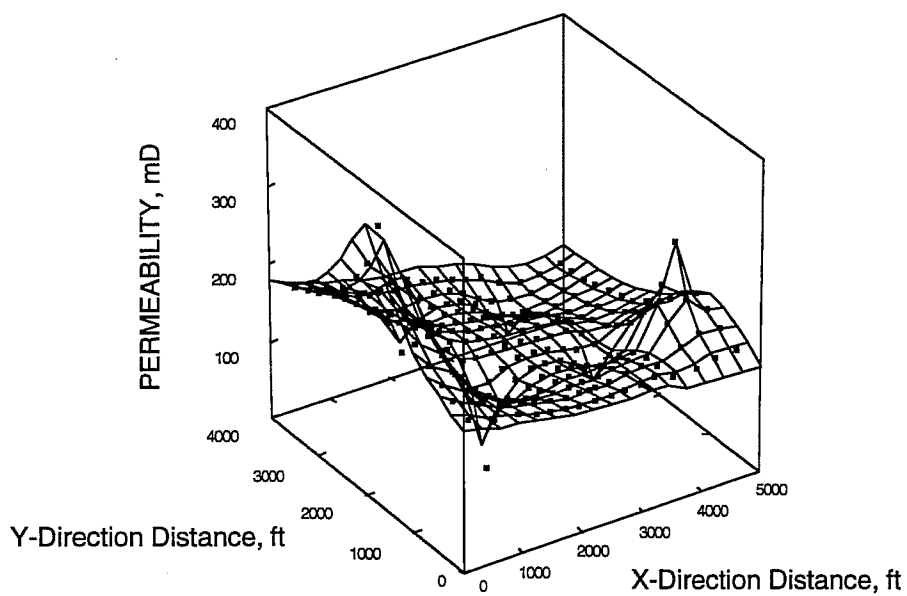Fig. 3a - Permeability distribution of layer 1.

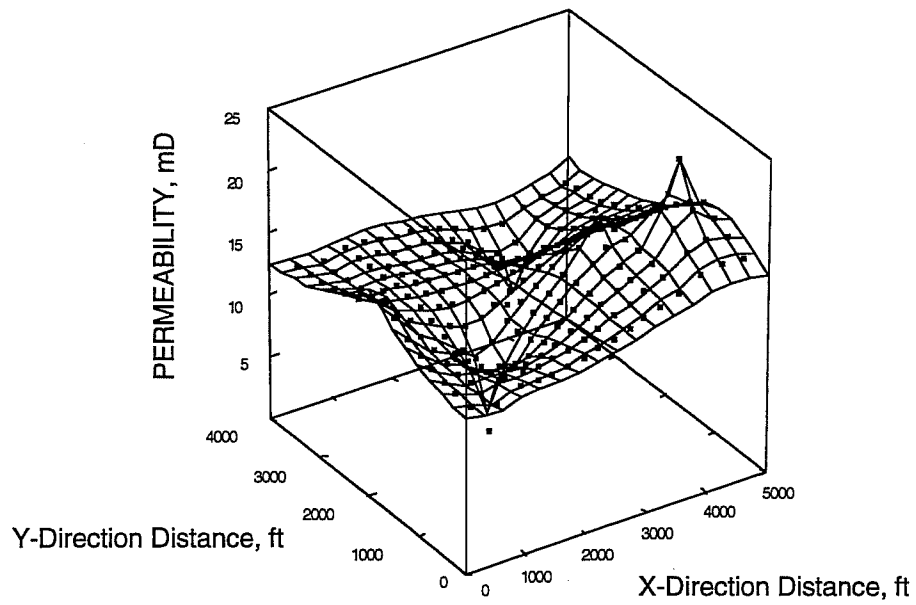

Fig. 3b - Permeability distribution of layer 2

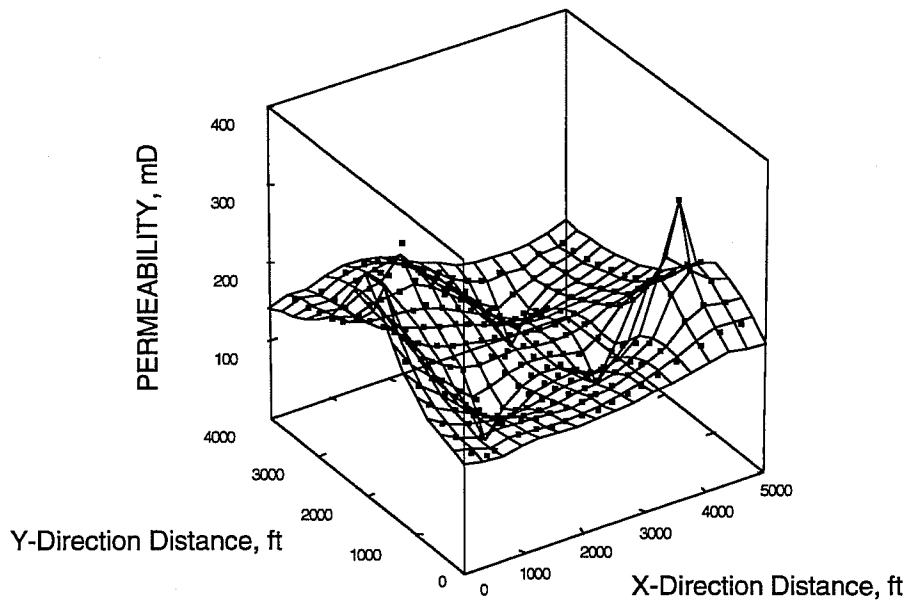Fig. 3c - Permeability distribution of layer 3.

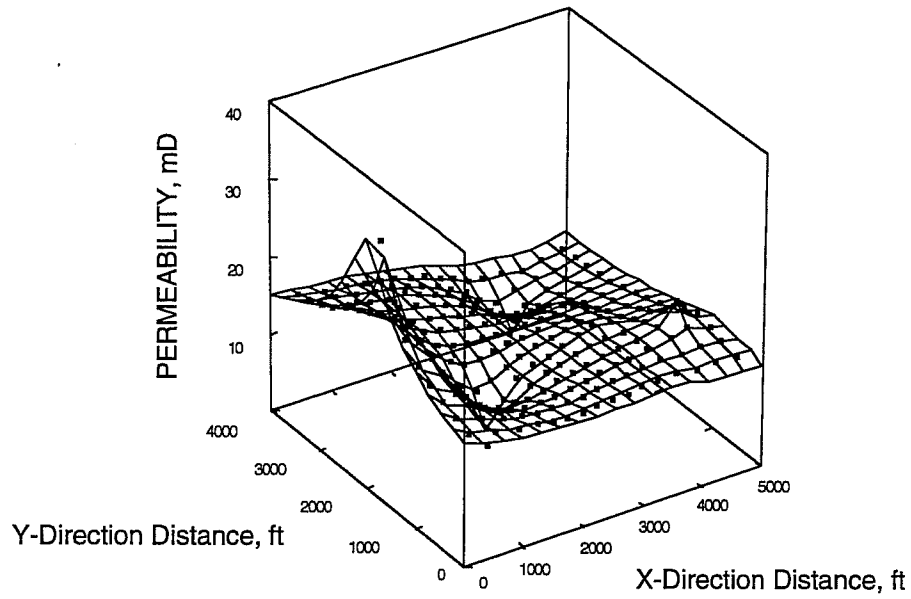Fig. 3d - Permeability distribution of layer 4.

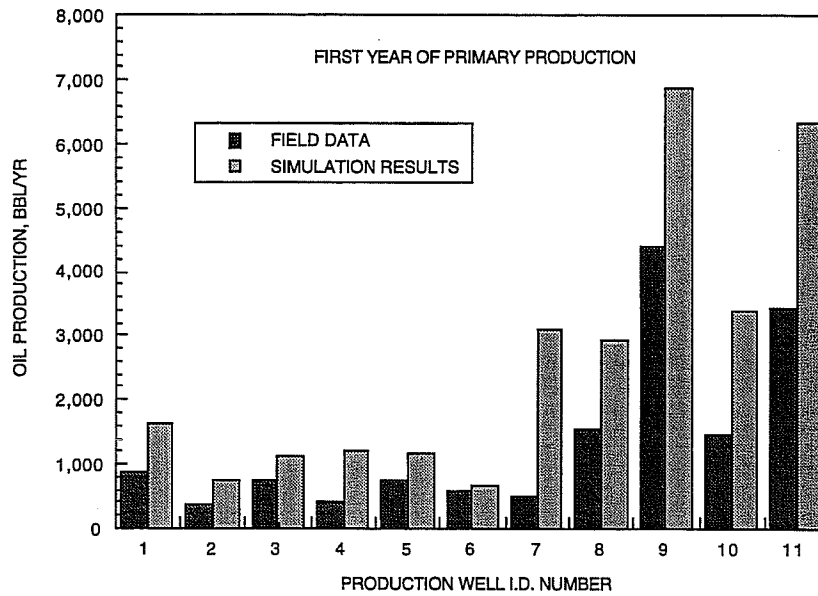Fig. 3e - Permeability distribution of layer 5.

Fig. 4 - Comparison of oil production from simulator and field performance during the first year of primary production.
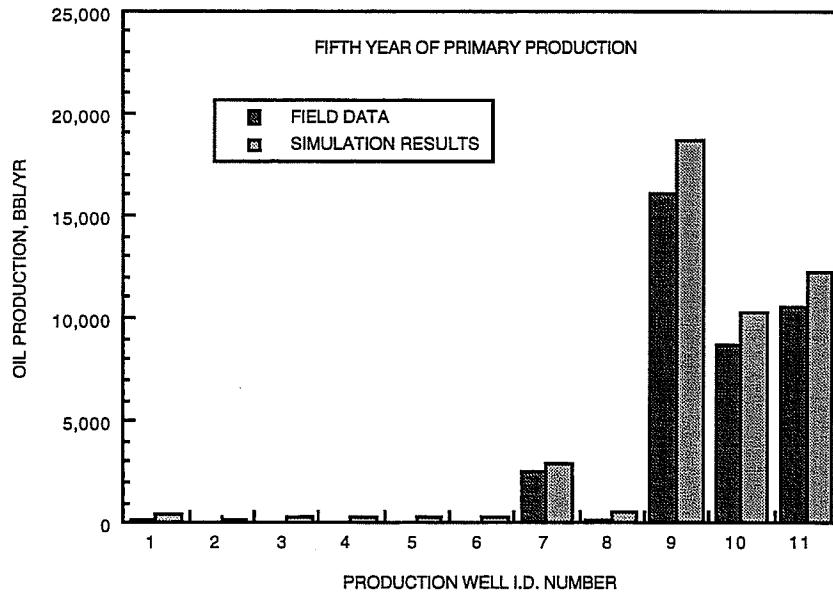
Fig. 5 - Comparison of oil production from simulator and field performance during the fifth year of primary production.
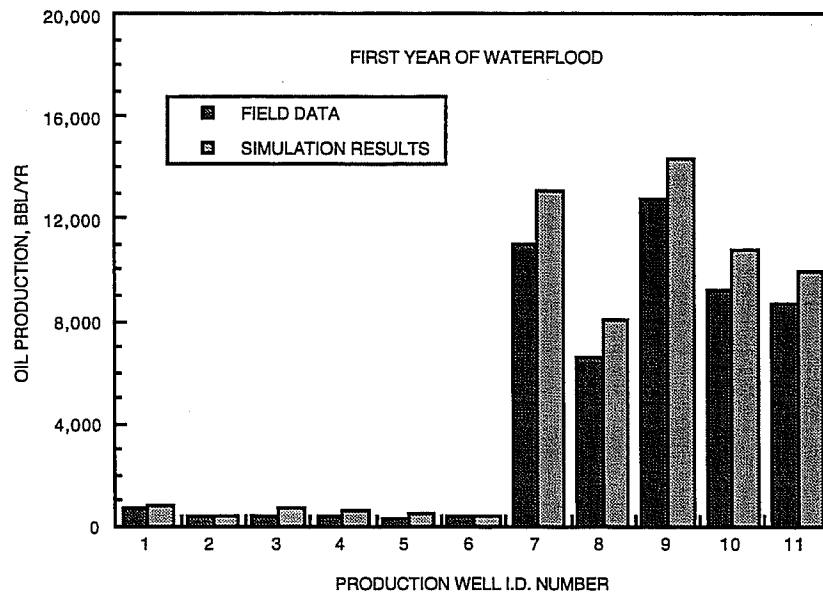

Fig. 6 - Comparison of oil production from simulator and field performance during the first year of waterflooding.
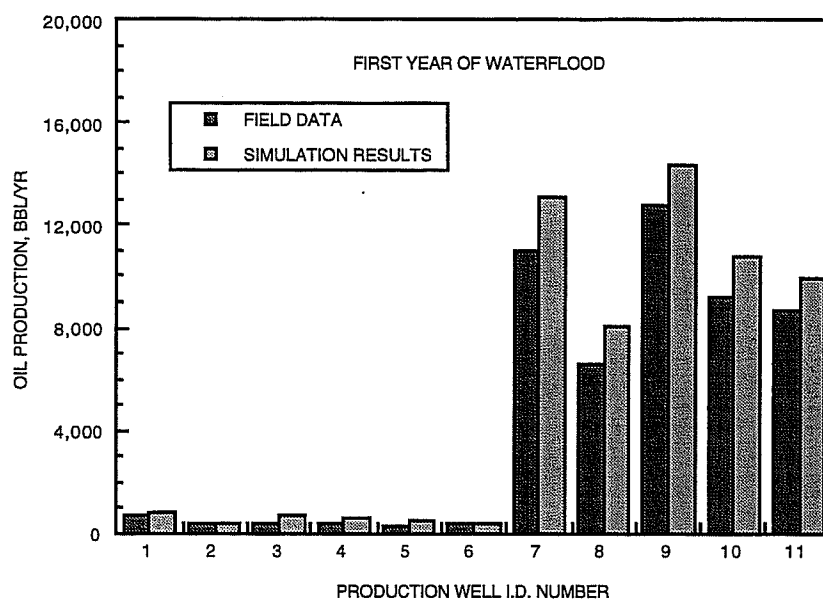
Fig. 7 - Comparison of oil production from simulator and field performance during the third year of waterflooding.
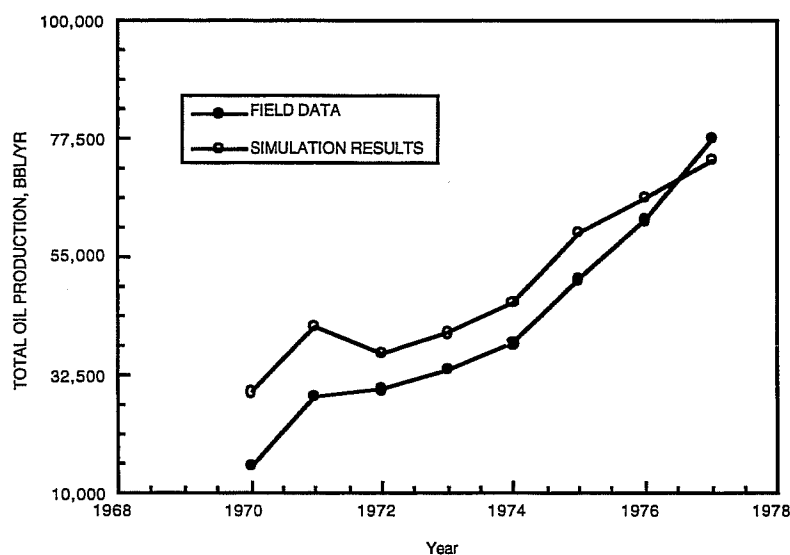

Fig. 8 - Comparison of annual oil production from simulator and field performance during primary production and the first three years of waterflooding.

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